

shall be stored in a location readily accessible to the drilling crew;

(ii) An inside BOP and an essentially full-opening, drill-string safety valve in the open position on the rig floor at all times while drilling operations are being conducted. These valves shall be maintained on the rig floor to fit all connections that are in the drill string. A wrench to fit the drill-string safety valve shall be stored in a location readily accessible to the drilling crew;

(iii) A safety valve available on the rig floor assembled with the proper connection to fit the casing string being run in the hole; and

(iv) Locking devices installed on the ram-type preventers.

(e) *BOP requirements.* Prior to drilling below cap rock casing, a BOP system shall be installed consisting of at least three remote-controlled, hydraulically operated BOP's including at least one equipped with pipe rams, one with blind rams, and one annular type.

(f) *Tapered drill-string operations.* Prior to commencing tapered drill-string operations, the BOP stack shall be equipped with conventional and/or variable-bore pipe rams to provide either of the following:

(1) One set of variable bore rams capable of sealing around both sizes in the string and one set of blind rams, or

(2) One set of pipe rams capable of sealing around the larger size string, provided that blind-shear ram capability is present, and crossover subs to the larger size pipe are readily available on the rig floor.

§ 250.1611 Blowout preventer systems tests, actuations, inspections, and maintenance.

(a) Prior to conducting high-pressure tests, all BOP systems shall be tested to a pressure of 200 to 300 psi.

(b) Ram-type BOP's and the choke manifold shall be pressure tested with water to rated working pressure or as otherwise approved by the District Manager. Annular type BOP's shall be pressure tested with water to 70 percent of rated working pressure or as otherwise approved by the District Manager.

(c) In conjunction with the weekly pressure test of BOP systems required in paragraph (d) of this section, the

choke manifold valves, upper and lower kelly cocks, and drill-string safety valves shall be pressure tested to pipe-ram test pressures. Safety valves with proper casing connections shall be actuated prior to running casing.

(d) BOP system shall be pressure tested as follows:

(1) When installed;

(2) Before drilling out each string of casing or before continuing operations in cases where cement is not drilled out;

(3) At least once each week, but not exceeding 7 days between pressure tests, alternating between control stations. If either control system is not functional, further drilling operations shall be suspended until that system becomes operable. A period of more than 7 days between BOP tests is allowed when there is a stuck drill pipe or there are pressure control operations and remedial efforts are being performed, provided that the pressure tests are conducted as soon as possible and before normal operations resume. The date, time, and reason for postponing pressure testing shall be entered into the driller's report. Pressure testing shall be performed at intervals to allow each drilling crew to operate the equipment. The weekly pressure test is not required for blind and blind-shear rams;

(4) Blind and blind-shear rams shall be actuated at least once every 7 days. Closing pressure on the blind and blind-shear rams greater than necessary to indicate proper operation of the rams is not required;

(5) Variable bore-pipe rams shall be pressure tested against all sizes of pipe in use, excluding drill collars and bottomhole tools; and

(6) Following the disconnection or repair of any well-pressure containment seal in the wellhead/BOP stack assembly. In this situation, the pressure tests may be limited to the affected component.

(e) All BOP systems shall be inspected and maintained to assure that the equipment will function properly. The BOP systems shall be visually inspected at least once each day. The manufacturer's recommended inspection and maintenance procedures are

acceptable as guidelines in complying with this requirement.

(f) The lessee shall record pressure conditions during BOP tests on pressure charts, unless otherwise approved by the District Manager. The test duration for each BOP component tested shall be sufficient to demonstrate that the component is effectively holding pressure. The charts shall be certified as correct by the operator's representative at the facility.

(g) The time, date, and results of all pressure tests, actuations, inspections, and crew drills of the BOP system and system components shall be recorded in the driller's report. The BOP tests shall be documented in accordance with the following:

(1) The documentation shall indicate the sequential order of BOP and auxiliary equipment testing and the pressure and duration of each test. As an alternate, the documentation in the driller's report may reference a BOP test plan that contains the required information and is retained on file at the facility.

(2) The control station used during the test shall be identified in the driller's report.

(3) Any problems or irregularities observed during BOP and auxiliary equipment testing and any actions taken to remedy such problems or irregularities shall be noted in the driller's report.

(4) Documentation required to be entered in the driller's report may instead be referenced in the driller's report. All records, including pressure charts, driller's report, and referenced documents, pertaining to BOP tests, actuations, and inspections, shall be available for BSEE review at the facility for the duration of the drilling activity. Following completion of the drilling activity, all drilling records shall be retained for a period of 2 years at the facility, at the lessee's field office nearest the OCS facility, or at another location conveniently available to the District Manager.

§250.1612 Well-control drills.

Well-control drills shall be conducted for each drilling crew in accordance with the requirements set forth in §250.462 of this part or as approved by the District Manager.

§250.1613 Diverter systems.

(a) When drilling a conductor or cap rock hole, all drilling units shall be equipped with a diverter system consisting of a diverter sealing element, diverter lines, and control systems. The diverter system shall be designed, installed, and maintained so as to divert gases, water, mud, and other materials away from the facilities and personnel.

(b) The diverter system shall be equipped with remote-control valves in the flow lines that can be operated from at least one remote-control station in addition to the one on the drilling floor. Any valve used in a diverter system shall be full opening. No manual or butterfly valves shall be installed in any part of a diverter system. There shall be a minimum number of turns in the vent line(s) downstream of the spool outlet flange, and the radius of curvature of turns shall be as large as practicable. Flexible hose may be used for diversion lines instead of rigid pipe if the flexible hose has integral end couplings. The entire diverter system shall be firmly anchored and supported to prevent whipping and vibrations. All diverter control equipment and lines shall be protected from physical damage from thrown and falling objects.

(c) For drilling operations conducted with a surface wellhead configuration, the following shall apply:

(1) If the diverter system utilizes only one spool outlet, branch lines shall be installed to provide downwind diversion capability, and

(2) No spool outlet or diverter line internal diameter shall be less than 10 inches, except that dual spool outlets are acceptable if each outlet has a minimum internal diameter of 8 inches, and both outlets are piped to overboard lines and that each line downstream of the changeover nipple at the spool has a minimum internal diameter of 10 inches.

(d) The diverter sealing element and diverter valves shall be pressure tested to a minimum of 200 psi when nipped upon conductor casing. No more than 7 days shall elapse between subsequent pressure tests. The diverter sealing element, diverter valves, and diverter control systems (including the remote)